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TOPICAL REPORT

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by

Ravi Parmeswar, Nicida L. Maerefat,
and Alan Brinkmeyer

Work Performed for the
U.S. Department of Energy
Under Cooperative Agreement DE-FC22-83FE60149

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Project BE9, Task 1, Milestone 6, FY87

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ILLUSTRATION

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ABSTRACT

Two- and three-phase relative permeability experiments were conducted on a Berea sandstone cores for two systems. The first system used a 4.1-cp oil mixture, and the other system used a 47-cp oil mixture. The other two phases are nitrogen and brine. The steady-state method was used. End effects were eliminated by measuring pressures and saturations at the center portion of the core. The oil and brine saturations were determined by using the x-ray absorption and microwave absorption techniques, respectively. The gas saturation was determined by material balance. Accordingly with the literature, this is the first study ever reported on the effect of oil viscosity on three-phase relative permeability in a gas, oil brine system.

Three-phase relative permeability results for the systems are presented and compared. The results show that the relative permeability to brine is a function of the brine saturation alone for both systems studied; increasing the oil viscosity lowered the relative permeability to brine by a factor of 10. The relative permeability to oil is a function of all three saturations, and the shapes of the oil isoperms are concave towards the 100 percent oil apex. The relative permeability to the high-viscosity oil seems to be less dependent on the gas and brine saturations than the relative permeability to low-viscosity oil. The gas relative permeability isoperms are concave toward the 100 percent gas apex, indicating that the relative permeability to gas is a function of all three saturations. However, comparison of the two isoperms for low- and high-viscosity oil systems reveals that the saturation of high-viscosity oil has more influence on the relative permeability to gas than the low-viscosity oil saturation does.

INTRODUCTION

Advanced reservoir engineering designs, oil recovery predictions, and evaluations of enhanced oil recovery methods incorporate relative permeability data. These data are used in reservoir simulators to evaluate reservoirs and predict oil recovery.

Recovery efficiency has been found to be dependent on the capillary number, a dimensionless number describing the ratio of viscous to capillary forces. Viscous forces are functions of fluid viscosity, flow velocity, and flow path length. Capillary forces vary with the fluid interfacial tension (IFT), wettability, and the pore geometry of the medium.[1]

Only two studies have been made concerning the effect of capillary number on two-phase relative permeabilities.[2-3] The variables within the group (velocity, interfacial tension, and viscosity) and their combined effect on two-phase relative permeabilities have been studied to some extent.[4-13] Conversely, reports on studies showing the effect of viscous and capillary forces on three-phase relative permeabilities have been reported for a low interfacial tension, brine-oil-surfactant-alcohol mixture,[14] but no work in this area has been reported for a gas-oil-water system.

The study of three-phase relative permeability has been largely neglected because of the complexity of the experiments and the required mathematical analysis. Recent improvements in laboratory instrumentation; that is, nuclear magnetic resonance imaging (NMRI), computer tomography (CT), x-ray and microwave absorption techniques, and the advent of high-speed digital computers have changed this situation. At present, measurement of three-phase relative permeability data is possible, although still cumbersome.

Results of limited research available on three-phase flow phenomena have shown that the fluid saturation regime of three-phase flow is narrow; however, the presence of a third phase has a profound influence on the transport properties of the other two phases in any porous medium. To understand this type of flow, three-phase relative permeability data must be determined accurately.

The results presented in this report are part of a study on the effects of viscous and capillary forces on three-phase relative permeability behavior. Only the effect of viscosity on three-phase relative permeability is described in this particular report.

Future experiments will be performed to determine the effects of fluid velocity and interfacial tension on three-phase relative permeability. The feasibility of defining a dimensionless number(s) (equivalent to the capillary number in two-phase relative permeability) will be investigated to determine whether such number(s) can totally account for changes in three-phase relative permeability or whether one or more of its parameters, such as fluid velocity, fluid viscosity, or interfacial tension are the controlling variables.

MATERIALS AND EXPERIMENTAL PROCEDURE

The rock used in these flow tests was a rectangular Berea sandstone core. Dimensions of the core were 1 in. width, 1½ in. height and 3 in. length. A core 12 in. in length, 1 in. in width and 1½ in. in height was used for the low viscosity tests. The cores were fired at 800° F for 24 hours to stabilize clays. The gas absolute permeability of these cores was from 600 to 700 md.

The fluids used in flow tests were 1 percent NaCl brine (μ = 0.989 cp), 7 percent iodododecane in paraffin oil (μ = 47 cp), and bottled nitrogen (μ = 0.01765 cp). For the low viscosity test, 10 percent iodododecane in Soltrol-220 was used as the oil phase. The nitrogen was allowed to bubble through a column of brine before it was introduced into the core. The x-ray/microwave technique[15] was used for determining fluid saturation.

Core Preparation

Precut rectangular Berea sandstone sections were cut to the desired length. The core was coated with a thin layer of epoxy to attach end caps and to prevent any core wrapping fluid from entering the core. The core was then wrapped with alternating layers of acrylic polyester resin and medical gauze. We allowed the resin to dry for 24 hours. Two pressure taps 1-inch apart at equal distance from the ends of the core were provided. After this preparation, the core was tested for leaks. The core permeability to nitrogen was measured at this stage.

Calibration Procedure

The core was positioned on the x-ray/microwave scanning table so that the x-ray and microwave beams were aligned with the center of the core. The core should be fixed to the track so as to prevent any movement during subsequent tests. The beginning and ending table positions for the x-ray absorption and microwave attenuation scans were also determined at this time.

The proper x-ray configurations for the core of interest were determined. The window settings were determined by running a pulse height distribution curve. The x-ray power level (45 kV and 10 mA) was also determined at this point. After the proper x-ray power level and window settings were established, as well as the necessary table configurations, the x-ray and microwave equipment was calibrated for determining oil and brine saturation.

In the high viscosity (47-cp) flow tests, the oil was tagged with iodododecane which gave the oil the necessary absorption for use with the x-ray. A 1- percent NaCl brine was used in calibrating the microwave. The following steps were followed during the calibration: (a) weigh the dry core, (b) scan the dry core at 6.3-mm intervals with the x-ray and microwave, (c) vacuum saturate the core with untagged Soltrol-220 oil by pulling a vacuum on the core system for 3 hours and introducing the oil, (d) flood the core with untagged Soltrol-220 and determine the absolute permeability, (e) compare this absolute permeability with the nitrogen permeability determined earlier, (f) weigh the core and determine the porosity and pore volume of the core, (g) flood the core with a minimum of 20 pore volumes of a 7-percent iodododecane/paraffin oil mixture, and (h) scan the core with the x-ray and microwave at the same intervals and positions as above. Similar procedure was followed for the low viscosity (4.1-cp) flow tests.

The data obtained were used to calibrate the system for x-ray and microwave measurements. The x-ray system was calibrated for oil saturation from the 100 percent untagged oil saturated core as oil free core (simulation of no presence of oil) and the 100 percent tagged oil saturated core as fully oil saturated. All subsequent oil saturations will fall on the straight line between these 0 and 100 percent values. A point-by-point calibration along the length of the core is most accurate. This type of calibration will take into account any inconsistency in the core wrapping or porosity variations

along the length of the core.

The microwave system was also calibrated in a similar point-by-point fashion at various brine saturations. Different brine saturations were attained during two-phase brine/oil flow tests by varying the brine and oil flowrate ratio. Two-phase relative permeability was measured at this time. The brine saturation at each point was determined by $S_w = 1-S_o$ where S_o was calculated from the previously mentioned x-ray calibration. Three-phase flow tests can be performed after calibration. The x-ray absorption system was used to measure oil saturation, and the microwave attenuation system was used to measure the brine saturation.

Steady-State Test

Steady-state, three-phase relative permeability flow tests required the measurement of the differential pressure across a pre-determined section of the core, the saturation of each fluid throughout this section, and the flow rates of the three fluids. The saturations of the brine and oil phases were determined from the microwave and x-ray systems; the gas saturation was determined by mass balance. Validyne pressure transducers with appropriate diaphragms (depending on core permeability and fluid flow rates) were used to measure the differential pressure across the central portion of the core. The flow rates were measured at the effluent end of the core after the core had attained steady-state. The flow rate ranges for these tests were as follows: 0-65 ml/hr for the brine phase, 0-50 ml/hr for the oil phase and 0-30,000 cm^3/hr for the gas phase. Saturation histories were controlled by maintaining two constant flow rates and varying the third flow rate. Steady-state was inferred when the fluid saturations and pressures remained constant over a 2-hour flow test period. Steady-state normally required 8 to 16 hours, depending on the flow rate to achieve the 2-hour period.

EXPERIMENTAL RESULTS - DISCUSSION

The brine, gas and oil relative permeability data obtained for the low viscosity system (oil viscosity 4.1-cp) and the high viscosity system (oil viscosity 47-cp) are plotted in figure 1, respectively. The two- and three-phase relative permeability data were plotted using the graphical contouring technique developed at NIPER which uses a three-dimensional interpolation

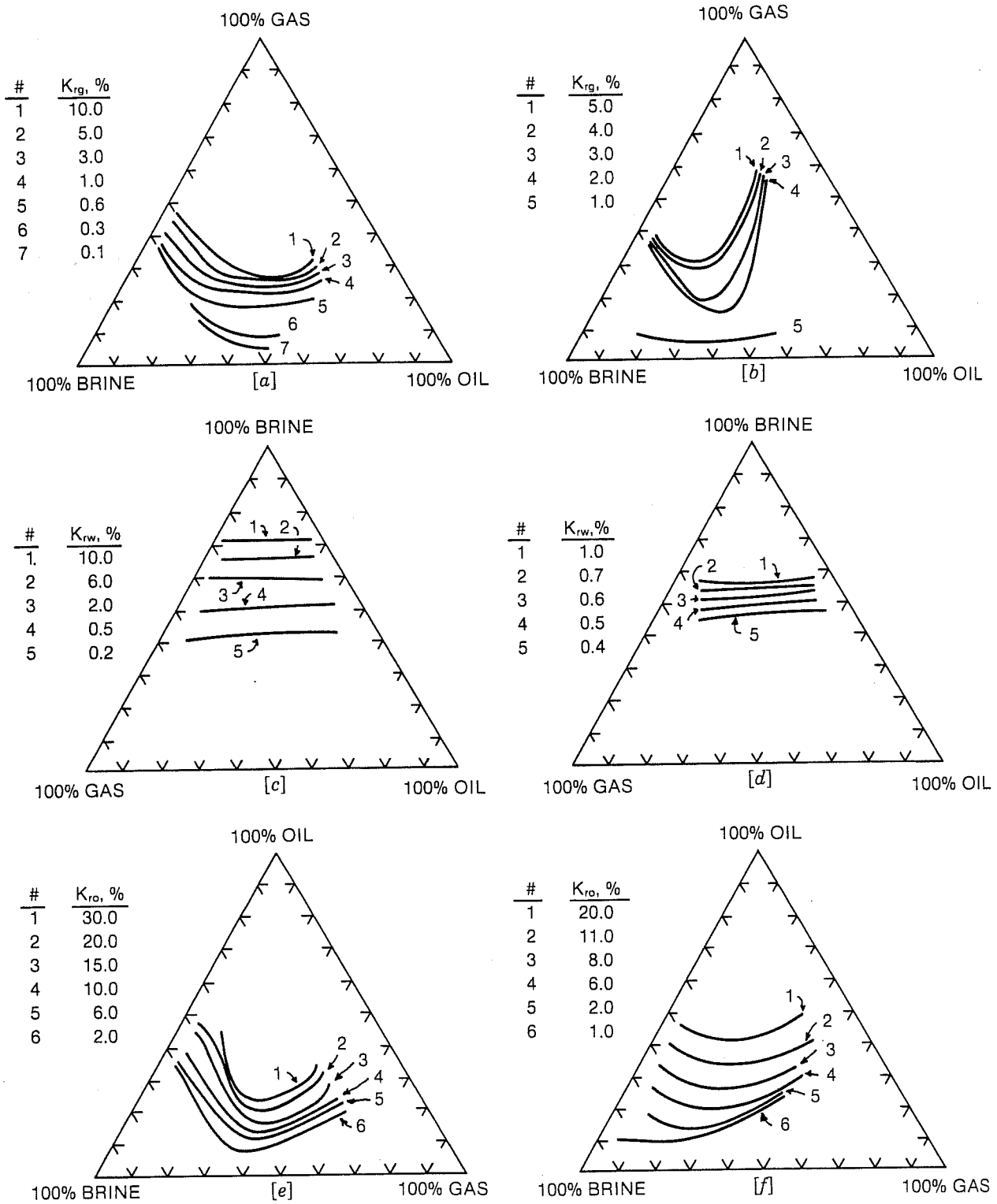

FIGURE 1. - Multiphase flow isoperms: (a) gas isoperms - low oil viscosity system; (b) gas isoperms - high oil viscosity system; (c) brine isoperms - low oil viscosity system; (d) brine isoperms - high oil viscosity system; (e) oil isoperms - low oil viscosity system; (f) oil isoperms - high oil viscosity system.

technique.[16] These procedures eliminate errors due to subjective bias.

The shapes of the isoperms of a phase are either convex, concave, or linear towards the 100 percent apex of that phase. To determine what each behavior means, consider the oil isoperms as an example. An oil isoperm convex toward the 100 percent oil apex indicates that the oil relative permeability is lower when both brine and gas are present than in the presence of either brine or gas alone. A linear oil isoperm indicates that the oil relative permeability is only a function of its own saturation; thus, it is independent of the ratio of brine and gas saturations. Similarly, a concave oil isoperm towards the 100 percent oil apex would indicate higher oil relative permeabilities when both gas and brine are present than in the presence of either brine or gas alone. Similar explanations can be given for gas and water isoperms.

The shape of the brine isoperms for the low and high oil viscosity systems are linear (Figs. 1c and 1d). The results indicate that the brine relative permeability in a three-phase system is a function of the brine saturation only. Comparing figures 1c and 1d, it is evident that for a given brine saturation, the brine permeability decreases significantly (approximately a factor of 10) when the viscosity of oil increases by a factor of ten.

The oil isoperms for the low- and high-viscosity systems are concave towards the 100 percent oil apex (Figs. 1e and 1f). Similar results have been reported by previous investigators for low oil viscosity systems. The behavior of the oil isoperm thus indicates that the oil relative permeability is a function of all three saturations. Data have not been reported on viscous oil systems; hence, no comparison can be made. The oil permeability increases in the presence of a third phase. Comparing figures 1e and 1f, it may be concluded that the oil relative permeability in the high-oil-viscosity system is less dependent on the brine and gas saturation. This is concluded from the flattening or the less concavity observed in the isoperms. To the contrary, in the low oil viscosity system, for a constant oil saturation at low brine saturation, the oil permeability does not change appreciably with small changes in brine saturation and is very sensitive to changes in gas saturation. At low gas saturation (high brine saturation), the reverse is true; the oil permeability is less dependent on gas saturation and more dependent on brine saturation.

The gas isoperms for the viscous (47-cp oil) and less less viscous (4.1-cp) systems are concave towards the 100 percent gas apex. The degree of concavity is greater for the viscous system. This indicates that increasing the oil viscosity causes the gas relative permeability to be more dependent on the oil saturation.

CONCLUSIONS

Three-phase relative permeability experiments were conducted on similar systems to study the effect of the oil viscosity on gas, water, and oil relative permeabilities. The results indicate the following:

1. Brine relative permeability under three-phase flow conditions is a function of its own saturation only. As the viscosity of oil increases the relative permeability of brine decreases significantly (a factor of 10).

2. Oil relative permeability is a function of all three fluid saturations, and the shape of the isoperms is concave towards the 100 percent oil apex. As the oil viscosity increases the oil relative permeability shows less dependence on the brine and gas saturations.

3. The gas relative permeability is a function of all three saturations and the shape of the gas isoperm is concave towards the 100 percent gas apex. The influence of oil saturation on gas relative permeability increases with the increase in oil viscosity.

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